NON-PUBLIC?: N
ACCESSION #: 9102260303
LICENSEE EVENT REPORT (LER)

FACILITY NAME: COMANCHE PEAK - UNIT 1 PAGE: 1 OF 08

DOCKET NUMBER: 05000445

TITLE: REACTOR TRIP CAUSED BY INADEQUATE SETPOINTS ON THE GENERATOR
PRIMARY WATER HEAD TANK AND LESS THAN ADEQUATE REVIEW OF A PROCEDURE CHANGE
EVENT DATE: 01/23/91 LER #: 91-002-00 REPORT DATE: 02/22/91

OTHER FACILITIES INVOLVED: N/A DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 095

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: T.A.HOPE SUPERVISOR, COMPLIANCE TELEPHONE: (817) 897-6370

COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

On January 23, 1991, Comanche Peak Steam Electric Station was in Mode 1, Power Operation, with the reactor at 95 percent of rated thermal power. Operations personnel were in the process of draining the turbine-generator primary water system ion exchanger vessel in preparation for resin changeout. Due to an improperly established vessel isolation, level in the primary water head tank decreased to a point which allowed the introduction of the head tank cover gas into the system flow. The resultant loss of flow indication caused actuation of the generator protection circuit, which lead to a reactor trip. The cause of the event was incorrect head tank low alarm setpoint and an inadequate review of a procedure change. Corrective actions will include setpoint changes and correction to the operating procedure.

END OF ABSTRACT

1. DESCRIPTION OF THE REPORTABLE EVENT

A. REPORTABLE EVENT CLASSIFICATION

An event or condition that resulted in the manual or automatic actuation of any Engineered Safety Feature (ESF), including the Reactor Protection System (RPS).

B. PLANT OPERATING CONDITIONS BEFORE THE EVENT

On January 23, 1991, just prior to the event, Comanche Peak Steam Electric Station (CPSES) Unit 1 was in Mode 1, Power Operation, with reactor power at 95 percent.

C. STATUS OF STRUCTURES, SYSTEMS, OR COMPONENTS THAT WERE INOPERABLE AT THE START OF THE EVENT AND THAT CONTRIBUTED TO THE EVENT

At the time of the event, the generator primary water ion exchanger (EIIS:(TJ)(IX)) was being drained in preparation for resin replacement.

D. NARRATIVE SUMMARY OF THE EVENT, INCLUDING DATES AND APPROXIMATE TIMES

Prior to the event, the unit had experienced out of specification values for copper and dissolved oxygen in the generator primary water system. The system is used to remove heat from the generator stator and rotor. Following consultation with the vendor, a change to the system operating procedure was initiated to allow bypassing varying amounts of primary water flow around the palladium catalyst to control the dissolved oxygen within the prescribed range. Plant Chemistry personnel observed gradual decreases in the primary water copper content as the dissolved oxygen content was increased to and maintained within the recommended values. The copper content decreased to a steady state value which still exceeded the maximum limit of the specification, and it was concluded that the resin in the primary water ion exchanger had become depleted and required replacement.

A work order was initiated and a clearance prepared in accordance with applicable station procedures. The clearance was processed through the Control Room and reviewed by operating personnel at approximately 2300 CST on January 22, 1991. The on-duty Unit Supervisor (utility, licensed) completed a review of the clearance in preparation for removal of the primary water ion exchanger from service. During his

review, the Unit Supervisor discovered that the associated system operating procedure did not adequately specify the valve alignment required to isolate the primary water ion exchanger. His review revealed that the bypass valve (EIIS:(TJ)(V)) used to divert flow around the palladium catalyst must be closed to isolate the primary water ion exchanger. The Unit Supervisor initiated a change to that section of the system operating procedure used to isolate the ion exchanger vessel. The procedure change was processed as a normal change since the Unit Supervisor felt that the bypass valve could be closed by an Auxiliary Operator during the application of the clearance.

During shift turnover at approximately 0645 on January 23, the midnight shift Unit Supervisor relayed to the on-coming day shift Unit Supervisor (utility, licensed) the information concerning preparations for draining the ion exchanger vessel. Prior to alignment of the vessel for draining, the day shift Unit Supervisor sought clarification from the system engineer (utility, non-licensed) regarding the proper position of the bypass valve. During the telephone conversation, the Unit Supervisor understood the system engineer to say that the bypass valve was not required to be closed to isolate the primary water ion exchanger. The system engineer, on the other hand, understood the question to be related to proper bypass valve position for control of oxygen content in the primary water system. This miscommunication resulted in the bypass valve being left open during draining of the ion exchanger vessel.

Operating personnel proceeded with activities to isolate and drain the ion exchanger vessel per the existing revision of the system operating procedure. During this process, a slightly decreasing level trend was observed in the primary water head tank (EIIS:(TK)(TJ)). The head tank was filled to its normal operating level of 88 percent just prior to shift turnover.
The oncoming evening shift assumed responsibility for plant

operation at approximately 1500 hours on January 23, 1991. At 1636, the reactor (EIIS:(RCT)) tripped due to a turbine generator trip caused by low primary water flow to generator bushing C. Shortly after the trip, operating personnel observed that primary system flow was normal and the primary head tank level was 75 percent of indicated range, well above the low alarm setpoint of 65

percent. Control Room personnel responded in accordance with emergency operating procedures. All plant systems responded as expected, and the plant was stabilized in Mode 3, Hot Standby, at approximately 1700 hours. At approximately 1810 CST the NRC was notified of the event via the Emergency Notification System in accordance with 10CFR50.72.

E. THE METHOD OF DISCOVERY OF EACH COMPONENT OR SYSTEM FAILURE OR
PROCEDURAL ERROR

The reactor trip was annunciated by numerous alarms in the Control Room. The immediate cause of the event was identified during a system walkdown performed by the system engineer and the vendor representative (non-licensed) at approximately 1830 CST on January 23.

II. COMPONENT OR SYSTEM FAILURES

A. FAILED COMPONENT INFORMATION

Not applicable - there were no component failures associated with this event.

B. FAILURE MODE, MECHANISM, AND EFFECT OF EACH FAILED COMPONENT

Not applicable - there were no component failures associated with this event.

C. CAUSE OF EACH COMPONENT OR SYSTEM FAILURE

Not applicable - there were no component failures associated with this event.

D. SYSTEMS OR SECONDARY FUNCTIONS THAT WERE AFFECTED BY

FAILURE OF
COMPONENTS WITH MULTIPLE FUNCTIONS

Not applicable - there were no component failures associated with this event.

III. ANALYSIS OF THE EVENT

A. SAFETY SYSTEM RESPONSES THAT OCCURRED

The Reactor Protection System (EIIS:(JC)) and Auxiliary Feedwater System (EIIS:(BA)) actuated during the event; all associated components within these systems functioned as designed.

B. DURATION OF SAFETY SYSTEM TRAIN INOPERABILITY

Not applicable - there were no safety systems which were rendered inoperable due to or during this event.

C. SAFETY CONSEQUENCES AND IMPLICATIONS OF THE EVENT

A turbine trip initiated by a generator trip leads to a reduction in the capability of the secondary system to remove heat generated in the reactor core. This event is analyzed in Section 15.2.3 of the CPSES Final Safety Analysis Report. The analysis uses conservative assumptions to demonstrate the capability of pressure relieving devices and to demonstrate core protection margins. The event of January 23, 1991, occurred at 95 percent reactor power, and all systems and components functioned as designed. The event is completely bounded by the FSAR accident analysis which assumes an initial power level of 102 percent and conservative assumptions which reduce the capability of safety systems to mitigate the consequences of the transient. It is concluded that the event of January 23 did not adversely affect the safe operation of CPSES Unit 1 or the health and safety of the public.

IV. CAUSE OF THE EVENT

IMMEDIATE CAUSE

When level in the primary water head tank dropped below 80 percent due to draining of the primary water ion exchanger, hydrogen gas which blankets the surface of the water in the primary water head tank was drawn into the primary water system flow path. The bubbles present in the system flow caused a momentary loss of indicated flow to generator bushing C, causing actuation of the generator protection circuit. This lead to a turbine trip and a reactor trip.

ROOT CAUSE NO. 1

The technical review of the change to the generator primary water system operating procedure to allow for bypass operation of the paladium catalyst was less than adequate. Operation of the system with the bypass valve open impacted the section of the procedure used for isolating the ion exchanger, but the technical review of the change did not recognize that impact.

ROOT CAUSE NO. 2

The setpoints for the primary water head tank were not adequate to alert operating personnel prior to the introduction of cover gas into the system flow leading to the loss of flow indication. Evaluation by the vendor indicates the need to change the low level alarm setpoint from 65 percent to 85 percent.

CONTRIBUTING FACTOR

Less than adequate communication is considered to be a factor contributing to the event. Communication between the day shift Unit Supervisor and the System Engineer resulted in a misunderstanding of the proper bypass valve position for vessel isolation. Processing of a change to the operating procedure did not occur. This is considered another contributing factor. If the procedure change to the primary water system initiated by the midnight shift Unit Supervisor had been processed, the bypass valve through which head tank inventory was lost would have been required to be closed during the ion exchanger vessel draining process.

V. CORRECTIVE ACTIONS

A. IMMEDIATE

Operations personnel responded in accordance with the emergency operating procedures, stabilizing the plant in Mode 3, Hot Standby. Investigation was initiated to identify the cause of the trip. The event was documented in accordance with plant procedures to ensure incident investigation and resolution.

B. ACTIONS TO PREVENT RECURRENCE

Root Cause Less than adequate technical review

Corrective Action Individuals within the affected organizations will be advised via the "Lessons Learned" process of the importance of comprehensive reviews of procedure changes. The system operating procedure for the primary water system has been changed to properly address the actions necessary to remove the primary water ion exchanger from service.

Root Cause Less than adequate setpoints

Corrective Action A shift order was immediately implemented for Operations personnel to maintain the tank level in the 90 to 94% range. This shift order is consistent with existing operating procedures which allow for the level to be maintained between 80 and 95%. The shift order effectively restricts the procedural operating band to levels at which recurrence is prevented. Corresponding procedures are being revised to incorporate this information.

Previous system operating experience led to a request for a setpoint evaluation by the turbine vendor. The completed evaluation has been received and confirms the need for revised setpoints. A setpoint change has been initiated to correc
the
inadequacies associated with the current setpoint.

Contributing Factors Less than adequate communication and processing of procedure changes.

Corrective Actions Shift operations personnel will be informed of the importance of implementation of procedure changes which affect the operation of sensitive equipment. Additionally, technical support personnel will be informed of the desirability of communicating information through the use of procedure changes and the shift order process.

VI. PREVIOUS SIMILAR EVENTS

There have been no previous reactor trips attributable to the causes identified during the event investigation.

ATTACHMENT 1 TO 9102260303 PAGE 1 OF 1

Log # TXX-91089
File # 10200
910.4
Ref. # 50.73(a)(2)(iv)
TUELECTRIC
February 22, 1991

W. J. Cahill
Executive Vice President

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NO. 50-445
MANUAL OR AUTOMATIC REACTOR PROTECTION SYSTEM ACTUATION
LICENSEE EVENT REPORT 91-002-00

Gentlemen:

Enclosed is Licensee Event Report 91-002-00 for Comanche Peak Steam Electric Station Unit 1, "Reactor Trip Caused by Inadequate Setpoints on the Generator Primary Water Head Tank and Less Than Adequate Review of a Procedure Change."

Sincerely,

William J. Cahill, Jr.

JAA/bm

c - Mr. R. D. Martin, Region IV
Resident Inspectors, CPSES (3)

400 Olive Street LB 81 Dallas, Texas 75201

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